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ELECTRIC POWER ANNUAL REPORT

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HISTORY
1984–88

* * * *

PROJECTIONS
1989–98

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A REPORT OF THE
EDISON ELECTRIC
INSTITUTE

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A REPORT OF THE STATISTICS DEPARTMENT OF THE EDISON ELECTRIC INSTITUTE

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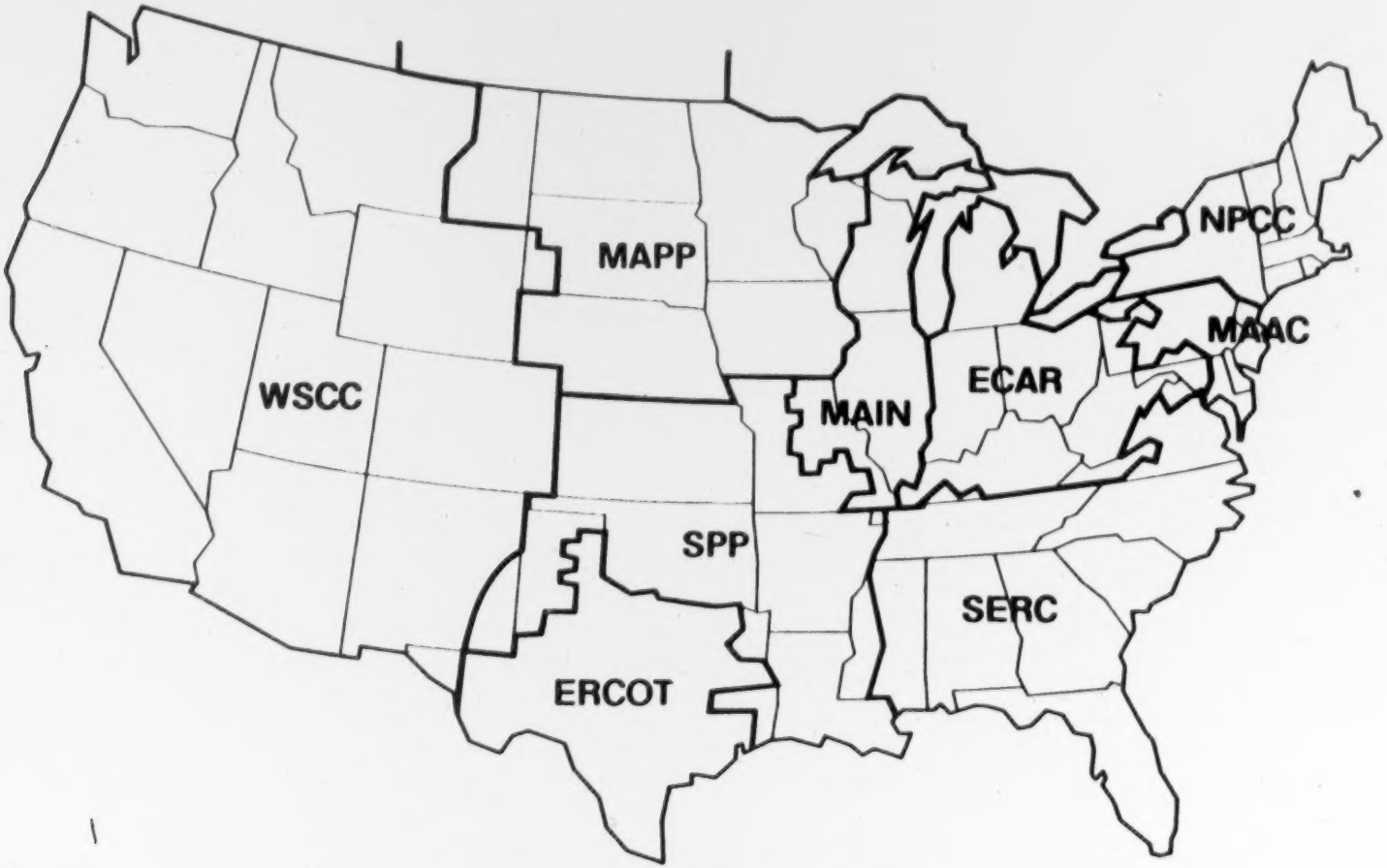
U.S. REGIONS OF THE NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

IDENTIFICATION OF RELIABILITY COUNCILS:

ECAR – East Central Area Reliability Coordination Agreement
ERCOT – Electric Reliability Council of Texas
MAAC – Mid Atlantic Area Council
MAIN – Mid America Interconnected Network
MAPP – Mid continent Area Power Pool
NPCC – Northeast Power Coordinating Council
SERC – Southeastern Electric Reliability Council
SPP – Southwest Power Pool
WSCC – Western Systems Coordinating Council

The electric utility systems of the United States are normally operated as three separate interconnected areas: the Eastern Interconnection, the Electric Reliability Council of Texas (ERCOT), and the Western Systems Coordinating Council (WSCC). Generating capacity available in one of these areas is not usually available to any other area. Also, generating capacity in one of the interconnected areas may not be available to serve load throughout that area due to various internal constraints.



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FOREWORD

This 1988 ELECTRIC POWER ANNUAL REPORT presents information concerning the electric power supply, expansion of electric generating facilities, and the manufacture of heavy electric power equipment in the United States as of the end of 1988.

The report is divided into three parts. Part I covers the history of electric power supply from 1984 through 1988. Part II pertains to projected power supply values from 1989 through 1998. Part III has to do with the planned domestic manufacture and importation of heavy electric power equipment as of January 1, 1989.

The historical data from 1984 through 1988 are an accurate presentation of the peak load, capability installed to meet load, and energy requirements for these time periods. The electric power supply data shown in Parts I and II of this report are derived from IE-411 reports for previous years submitted to the Department of Energy and to the North American Electric Reliability Council (NERC).

Forecast values used herein were obtained from IE-411 reports and from the advance release of ELECTRIC POWER SUPPLY & DEMAND 1989-1998 published by NERC in May of 1989. Installed capability, peak load and percent capacity margin values shown in this report for the summer of 1988 update the preliminary actual values published in EEI's 1988 POST-SUMMER ELECTRIC POWER SURVEY. The installed generating capability figures for summer 1988 and winter 1988/89 were reported to NERC in connection with its annual reliability review assessment.

Data in this report represent the total electric utility industry of the lower 48 states, including Investor-Owned systems and those of governmental agencies--Federal, Municipal and State & Local--and also Rural Electric Cooperatives.

The reported data include some industrial power installations whose operations are coordinated with the utility systems with which they are interconnected and which thereby contribute to the public supply. The data do not include any isolated industrial or institutional power installations.

Data pertaining to power system capabilities, peak loads, percent capacity margins, and energy requirements are presented for each of the nine reliability councils of NERC. Boundaries of the nine reliability councils are shown by the map in Fig. 1. The North American Electric Reliability Council encompasses essentially all utility systems in the United States and five Canadian provinces, but the data presented in this report cover only the systems in the contiguous United States.

Part III of this report presents the results of the semi-annual survey on the manufacture and scheduling of heavy electric power equipment as of January 1, 1989, conducted by the Statistics Department of the Edison Electric Institute. Contributors to the survey include representatives of the electric utility industry throughout the contigous United States, the nation's principal manufacturers of heavy electric power equipment, and those foreign manufacturers supplying electric generating equipment to U.S. electric utility systems.

The Edison Electric Institute is the only organization servicing the electric utility and allied industries that conducts surveys on the manufacture and scheduling of heavy electric power equipment on a semi-annual basis. These surveys are also unique in that information on each planned project is cross-checked with both the manufacturer and the system ordering the equipment. Furthermore, the time-frame for ordered and scheduled units is not limited to ten years, but extends into the future as far out as equipment is officially ordered and scheduled for installation. The resulting data file also allows the semi-annual tracking of unit slippages and cancellations.

Projections presented in this report are based on the best information available from the turn of the year through the end of the first quarter of 1989. There could, however, be delays in the installation of scheduled capacity and reductions in the percent capacity margins. To assure an adequate bulk electric power supply into the 1990s, it is essential that the installation of both nuclear and coal-fired generating units proceed as currently scheduled and that conservation and load management programs be pursued at the same time.

Definitions of the terms used in this report, together with information concerning methods of summarizing the data, appear on the following page.

DEFINITIONS AND METHODS OF SUMMARIZATION

INSTALLED CAPABILITY is the maximum load which a generating unit or a group of units can carry under specified conditions for a given period of time. Installed capability values are shown in the historical summer and winter tables.

CAPABILITY, as projected in this report, is equivalent to Planned Resources, defined by the North American Electric Reliability Council to include the total installed generating capacity which is existing, presently under construction, or in various states of planning; plus scheduled capacity purchases, less scheduled capacity sales; less total generating capacity out of service in deactivated shutdown status. This capability must provide for the projected load plus scheduled maintenance, forced outages, system operating requirements, and any unforeseen load. The capabilities of all systems normally interconnected are based upon fully coordinated operation. Peak capability refers to the maximum capability, as defined above, at the approximate time and for the duration of the load referred to, that is, at the time of the summer peak load or the winter peak load. Regional capability, as reported herein, is the sum of the capabilities of the systems serving the region.

PEAK LOAD for a region may be either coincident or non-coincident. It is the sum of the actual or projected peak load of the electric utilities and any self-generating industrial facilities.

HISTORICAL AND PROJECTED INSTALLED MARGIN shown on the summer and winter tables represents the difference between installed capability and peak load. It is the margin available to replace generating equipment out of service due to planned scheduled maintenance, foreced outages, and equipment deratings due to various causes. In addition, installed margin must provide an operating reserve to cover variations in peak load and to regulate frequency and control transmission tie-line schedules.

PERCENT CAPACITY MARGIN is the installed margin divided by capability multiplied by 100.

CAVEATS Because some maximum regional loads may occur in winter rather than in summer, the installed margin for the country as a whole is not necessarily valid with respect to the electric power situation at a particular time. It is also true that regional installed capacity margins (and hence the installed margin for the sum of the regions) in summer or winter have not always represented the minimum or the maximum margin. The extremes of installed capacity margins may be influenced, for example, by the date of bringing new large generating facilities into commercial operation in relation to the time of the annual peak loads--the addition of a very large generating unit just before the peak could give a larger margin during the peak period than that which existed before the time of peak. Also, in areas having high proportions of hydroelectric generating capacity, the lowest margins may occur at times other than when the load is at a maximum because of low capability resulting from minimum water for power generation.

The adequacy of projected power supply cannot be judged solely by the use of installed capacity margins without proper recognition of the potential impact of planned and forced outages of generating equipment. There have been several occasions within the past 15 years when the entire installed margin has been utilized to offset such outages of generating equipment, resulting in system-wide voltage reductions, interruption of interruptible loads, public appeals, and some interruption of firm customer load.

LOAD FACTOR is the ratio of the megawatthour output supplied during a designated period to the output that would have occurred had the peak experienced during that period been constant throughout the period. For example, annual percent load factor is calculated by multiplying annual megawatthour requirements by 100 and dividing by the product of the annual peak load and the number of hours in a year (8,760 in normal years, 8,784 in leap years).

NERC U.S., as used in this publication, is equivalent to the lower forty-eight contiguous states; Alaska and Hawaii are omitted.

AVERAGE ANNUAL COMPOUND GROWTH RATES are calculated on a point-to-point basis, either by taking the fourth root of the difference between the values for the first and fifth historical years in Tables 1, 2, and 4, or the ninth root of the difference between the first and tenth projected years in Tables 10, 11, and 13.

INSTALLATION OF NEW CAPACITY; CAPABILITIES, PEAK LOADS, MARGINS, AND ENERGY REQUIREMENTS

INDUSTRY PERFORMANCE IN 1988

During the year 1988 the electric utility systems of the contiguous United States put into operation 7,469 megawatts of new electric generating capacity. Table 7, which includes all units of 4 megawatts capacity and larger, shows that 3 units with capability ratings aggregating 40 megawatts were hydraulic, and 18 units totaling 7.4 thousand megawatts were thermal. Five of the thermal units were powered by nuclear fuel, and four were conventional steam turbine-generators. The individual generating units that make up the 7.5 thousand megawatts added during 1988 are identified in the actual additions listing on page 13.

This newly added capacity contributed to the increase in the total capability, or load-carrying ability, of the U.S. electric utility systems to 676.9 thousand megawatts at the year end--an increase of 2.1 percent over the total at the end of 1987.

Of the total capability of 676.9 thousand megawatts, approximately 88 percent is thermal and the rest is hydraulic. During the past five years the total capability of the country's electric utility systems has increased at an average annual rate of 2.1 percent.

The combined 1988 summer peak load, shown in Table 1 of this report, was 529.5 thousand megawatts or 13.5 percent higher than the 1988/89 winter peak load. This is the twenty-fifth consecutive year during which the combined summer peak load exceeded the peak of the following winter. The point-to-point compound average annual increase between the 1984 and 1988 summer peak loads was 4.1 percent.

As can be seen from Table 2, the combined winter 1988/89 peak load of the contiguous United States was 466.5 thousand megawatts--4.1 percent above the winter 1987/88 peak load. The change in peak load during the past five years, from winter 1984/85, was a net increase of 30.2 thousand megawatts, and is equivalent to an average annual increase of 1.7 percent on a point-to-point compounded basis.

Table 4 shows that during 1988 the energy requirements for the contiguous United States amounted to 2.8 billion megawatthours--4.4 percent higher than the output for 1987. The point-to-point compound average annual increase between 1984 and 1988 for energy requirements was 3.1 percent.

The 1988 annual load factor for the sum of the nine regions was 59.5 percent.

Table 1 - SUMMER INSTALLED CAPABILITIES, PEAK LOADS, INSTALLED MARGINS & PERCENT CAPACITY MARGINS (MW)

Regions		1984	1985	1986	1987	1988	88/87 % Chg	Growth Rate 1984-1988*
NPCC	Installed Capability	51,312	51,319	51,879	52,531	53,913	2.6	1.2%
	Peak Load	38,144	40,010	39,026	42,651	45,245	6.1	4.4%
	Installed Margin	13,168	11,309	12,853	9,880	8,668		
	Capacity Margin	25.7%	22.0%	24.8%	18.8%	16.1%		
MAAC	Installed Capability	46,183	47,157	47,626	48,553	48,669	0.2	1.3%
	Peak Load	35,442	37,053	37,527	40,526	43,110	6.4	5.0%
	Installed Margin	10,741	10,104	10,099	8,027	5,559		
	Capacity Margin	23.3%	21.4%	21.2%	16.5%	11.4%		
ECAR	Installed Capability	90,115	92,960	95,201	95,319	97,121	1.9	1.9%
	Peak Load	65,851	66,293	69,253	72,561	79,149	9.1	4.7%
	Installed Margin	24,264	26,667	25,948	22,758	17,972		
	Capacity Margin	26.9%	28.7%	27.3%	23.9%	18.5%		
SERC	Installed Capability	127,562	131,437	132,168	138,687	138,916	0.2	2.2%
	Peak Load	93,400	98,572	104,328	109,798	115,168	4.9	5.4%
	Installed Margin	34,162	32,865	27,840	28,889	23,748		
	Capacity Margin	26.8%	25.0%	21.1%	20.8%	17.1%		
MAIN	Installed Capability	41,608	44,568	45,351	44,805	49,336	10.1	4.4%
	Peak Load	35,186	32,432	35,968	37,458	41,139	9.8	4.0%
	Installed Margin	6,422	12,136	9,383	7,347	8,197		
	Capacity Margin	15.4%	27.2%	20.7%	16.4%	16.6%		
SPP	Installed Capability	60,389	62,225	65,102	66,342	66,221	-0.2	2.3%
	Peak Load	45,562	45,026	47,532	47,723	49,356	3.4	2.0%
	Installed Margin	14,827	17,199	17,570	18,619	16,865		
	Capacity Margin	24.6%	27.6%	27.0%	28.1%	25.5%		
ERCOT	Installed Capability	44,056	43,829	43,386	47,476	49,227	3.7	2.8%
	Peak Load	36,851	38,062	39,140	39,339	40,843	3.8	2.6%
	Installed Margin	7,205	5,767	4,246	8,137	8,384		
	Capacity Margin	16.4%	13.2%	9.8%	17.1%	17.0%		
MAPP	Installed Capability	28,161	28,685	28,438	28,586	30,775	7.7	2.2%
	Peak Load	20,666	19,936	21,245	23,162	24,899	7.5	4.8%
	Installed Margin	7,495	8,749	7,193	5,424	5,876		
	Capacity Margin	26.6%	30.5%	25.3%	19.0%	19.1%		
WSCC	Installed Capability	114,854	119,417	124,140	125,619	127,402	1.3	2.6%
	Peak Load	80,048	83,119	82,301	82,967	90,551	9.1	3.1%
	Installed Margin	34,806	36,298	41,839	42,852	36,851		
	Capacity Margin	30.3%	30.4%	33.7%	34.1%	28.9%		
NERC UNITED STATES**	Installed Capability	604,240	621,597	633,291	648,118	661,580	2.1	2.3%
	Peak Load	451,150	460,503	476,320	496,185	529,460	6.7	4.1%
	Installed Margin	153,090	161,094	156,971	151,933	132,120		
	Capacity Margin	25.3%	25.9%	24.8%	23.4%	20.0%		

* Compound annual growth rate from 1984 to 1988.

** U.S. totals are not meaningful and should not be used for policy purposes.

NOTE: For definitions of terms see page 5.

Table 2 - WINTER INSTALLED CAPABILITIES, PEAK LOADS, INSTALLED MARGINS & PERCENT CAPACITY MARGINS (MW)

Regions		1984/85	1985/86	1986/87	1987/88	1988/89	88/87 % Chg	Growth Rate 1984-1988*
NPCC	Installed Capability	53,076	52,984	53,418	54,500	55,914	2.6	1.3%
	Peak Load	37,321	38,233	37,976	41,902	42,951	2.5	3.6%
	Installed Margin	15,755	14,751	15,442	12,598	12,963		
	Capacity Margin	29.7%	27.8%	28.9%	23.1%	23.2%		
MAAC	Installed Capability	49,646	49,715	49,978	50,943	51,300	0.7	0.8%
	Peak Load	33,384	31,652	32,807	35,775	36,363	1.6	2.2%
	Installed Margin	16,262	18,063	17,171	15,168	14,937		
	Capacity Margin	32.8%	36.3%	34.4%	29.8%	29.1%		
ECAR	Installed Capability	94,304	95,750	96,664	98,986	98,688	-0.3	1.1%
	Peak Load	67,349	65,667	64,561	68,118	68,977	1.3	0.6%
	Installed Margin	26,955	30,083	32,103	30,868	29,711		
	Capacity Margin	28.6%	31.4%	33.2%	31.2%	30.1%		
SERC	Installed Capability	129,105	134,754	135,482	140,138	143,140	2.1	2.6%
	Peak Load	106,837	97,854	101,849	105,476	108,649	3.0	0.4%
	Installed Margin	22,268	36,900	33,633	34,662	34,491		
	Capacity Margin	17.2%	27.4%	24.8%	24.7%	24.1%		
MAIN	Installed Capability	44,589	46,319	46,215	48,057	50,305	4.7	3.1%
	Peak Load	27,805	29,060	28,036	30,618	30,631	0.0	2.4%
	Installed Margin	16,784	17,259	18,179	17,439	19,674		
	Capacity Margin	37.6%	37.3%	39.3%	36.3%	39.1%		
SPP	Installed Capability	60,971	63,956	64,812	65,897	66,515	0.9	2.2%
	Peak Load	35,112	34,618	33,877	34,472	35,649	3.4	0.4%
	Installed Margin	25,859	29,338	30,935	31,425	30,866		
	Capacity Margin	42.4%	45.9%	47.7%	47.7%	46.4%		
ERCOT	Installed Capability	44,163	44,036	44,880	48,167	50,654	5.2	3.5%
	Peak Load	31,937	29,776	28,730	31,399	34,628	10.3	2.0%
	Installed Margin	12,226	14,260	16,150	16,768	16,026		
	Capacity Margin	27.7%	32.4%	36.0%	34.8%	31.6%		
MAPP	Installed Capability	28,927	29,434	29,266	30,587	31,804	4.0	2.4%
	Peak Load	18,989	18,803	18,850	19,335	20,162	4.3	1.5%
	Installed Margin	9,938	10,631	10,416	11,252	11,642		
	Capacity Margin	34.4%	36.1%	35.6%	36.8%	36.6%		
WSCC	Installed Capability	117,344	119,527	126,006	125,702	128,620	2.3	2.3%
	Peak Load	77,640	77,997	76,171	81,182	88,523	9.0	3.3%
	Installed Margin	39,704	41,530	49,835	44,520	40,097		
	Capacity Margin	33.8%	34.7%	39.5%	35.4%	31.2%		
NERC UNITED STATES**	Installed Capability	622,125	636,475	646,721	662,977	676,940	2.1	2.1%
	Peak Load	436,374	423,660	422,857	448,277	466,533	4.1	1.7%
	Installed Margin	185,751	212,815	223,864	214,700	210,407		
	Capacity Margin	29.9%	33.4%	34.6%	32.4%	31.1%		

* Compound annual growth rate from 1984/85 to 1988/89.

** U.S. totals are not meaningful and should not be used for policy purposes.

NOTE: For definitions of terms see page 5.

RELATIONSHIP BETWEEN SUMMER AND WINTER PEAK LOADS 1974-1988

The relationship between the summer and winter peak loads in the different regions of the country, and also for the contiguous United States, are shown in the accompanying table, where the summer peak load in each case is expressed as a percentage of the winter peak load for the following season.

In those regions where the summer peak load has been characteristically higher than the peak during the following winter, the percentage figure has, expectedly, been above 100 percent. This has been true particularly in SPP and ERCOT, where, due to climatic conditions, heavy air conditioning loads during the summer months have caused peaks that far exceed those during the following winter.

From the mid-1960s to the mid-1970s summer peaks for the country as a whole generally exceeded the peaks for the following winter by increasing amounts. In 1970, and again in 1971, apparently normal summer peaks were followed by winter peaks depressed both by mild weather and reduced industrial loads. This combination produced summer to winter peak relationships of 111 percent and 112 percent respectively in 1970 and 1971. After falling back to 110 percent in 1972, the summer/winter ratio jumped to an all-time high of 117 percent in 1973 because of the unprecedented drop in the winter peak load from the previous year. The ratio lowered only one point in 1974 since both the summer and winter peak loads were little changed from those experienced in 1973. Through the rest of the 1970s the ratio fluctuated in the more normal range of between 106 and 108 percent. The hot summer of 1980 and the economic downturn of 1981 helped to produce values of 111 and 108 percent respectively. In 1982 the summer peak dropped 3.1 percent and the winter peak dropped 4.5 percent. The greater relative decline in the winter peak caused the summer/winter ratio to increase to 111 in 1982. The national ratio dropped to 109 percent in 1983. Then, due to a rebound in the 1984/85 winter peak load, the ratio fell to 103 percent in 1984--the lowest value registered since 1965. More normal ratios occurred in the nine regions in 1985, with the contiguous U.S. registering a value of 109 percent. In 1986 a slight decline in the national winter peak, coupled with a 3.4 percent increase in the summer peak, caused the summer/winter ratio to increase to 113 percent. A lesser increase in summer than in winter 1987 peak gave a value of 111 percent. In 1988, a summer increase in peak load of 6.7 percent, and only 4.1 percent in winter, increased the ratio of difference to 113 percent.

Table 3 - SUMMER PEAK LOADS EXPRESSED AS PERCENTAGE OF PEAK LOAD FOR THE FOLLOWING WINTER

Regions	74/75	75/76	76/78	77/78	78/79	79/80	80/81	81/82	82/83	83/84	84/85	85/86	86/87	87/88	88/89
NPCC	104	102	96	105	102	100	104	101	105	105	102	105	103	102	105
MAAC	123	114	108	115	111	114	116	109	120	115	106	117	114	113	119
ECAR	105	102	97	101	99	104	101	102	105	103	98	101	107	107	115
SERC	109	100	93	99	99	101	99	97	101	106	87	101	102	104	106
MAIN	125	119	122	122	118	123	127	121	129	123	127	112	128	122	134
SPP	156	124	144	144	139	133	147	139	132	128	130	130	140	138	138
ERCOT	157	141	142	142	134	130	132	128	131	118	115	128	136	125	118
MAPP	119	106	103	103	111	105	111	108	109	111	109	106	113	120	123
WSCC	107	104	107	107	98	100	107	105	105	98	103	107	108	102	102
NERC U.S	116	108	106	106	107	108	111	108	111	109	103	109	113	111	113

The 1988 energy requirements and annual load factors by reliability council are given in Tables 4 and 5, together with corresponding information for the previous four years. Table 4 shows that during 1988 electric energy requirements for the contiguous United States amounted to 2.8 billion megawatthours--4.4 percent higher than the output for 1987. The point-to-point average annual compound increase between 1984 and 1988 for energy requirements was 3.1 percent.

As can be seen from Table 5, the 1988 annual load factor for the sum of the nine regions was 59.5 percent. This dip below the usual value in the low 60 percent range was largely due to the greater relative increase in summer peak load compared to the increase in annual energy output.

Table 4 - ANNUAL ENERGY REQUIREMENTS (Megawatthours in Thousands)

Regions	1984	1985	1986	1987	1988	88/87 % Inc	Growth Rate 1984-1988*
NPCC	217,455	220,782	227,865	239,063	250,132	4.9%	3.2%
MAAC	186,034	189,671	197,056	207,007	218,636	5.0%	3.6%
ECAR	383,029	387,514	390,245	408,739	429,198	4.7%	2.9%
SERC	502,915	522,648	545,409	573,735	593,948	5.2%	4.0%
MAIN	170,930	173,589	177,190	181,972	194,101	2.7%	2.3%
SPP	225,642	229,677	216,501	228,260	237,179	5.4%	1.2%
ERCOT	185,283	190,758	190,796	195,400	201,472	2.4%	3.0%
MAPP	105,378	105,797	106,824	113,063	121,737	5.8%	2.5%
WSCC	468,937	478,790	480,218	496,293	522,455	3.3%	3.3%
NERC U.S.	2,445,603	2,499,226	2,532,104	2,643,532	2,768,858	4.4%	3.1%

* Average annual growth rate from 1984 to 1988.

Table 5 - ANNUAL PERCENT LOAD FACTOR

Regions	1984	1985	1986	1987	1988
NPCC	64.9	63.0	66.7	64.0	62.9
MAAC	59.8	58.4	59.9	58.3	57.7
ECAR	64.7	66.7	64.3	64.3	61.7
SERC	53.6	60.5	59.7	59.7	58.7
MAIN	55.3	61.1	56.2	55.5	53.7
SPP	56.4	58.2	52.0	54.6	54.7
ERCOT	57.2	57.2	55.6	56.7	56.2
MAPP	58.0	60.6	57.4	55.7	55.7
WSCC	66.7	65.8	66.6	68.3	65.7
NERC U.S.	59.7	62.0	60.7	60.8	59.5

CHANGES IN SCHEDULED OPERATION DATE OF NUCLEAR AND FOSSIL-FIRED STEAM TURBINE-GENERATORS
REMOVED FROM SCHEDULE AND DELAYED A YEAR OR MORE
BETWEEN JANUARY 1, 1988 AND JANUARY 1, 1989

Owner	Plant Name and Unit Number	Type	Nameplate Capacity MW	Net Expected Capability MW	Scheduled Operation Date as of January 1, 1988	Scheduled Operation Date as of January 1, 1989
Total Nuclear Units Removed from Schedule		None	-	-		
Tennessee Valley Authority	Bellefonte No. 1	N	1,218	1,213	1994	1998
Tennessee Valley Authority	Bellefonte No. 2	N	1,218	1,213	1996	200v
Tennessee Valley Authority	Watts Bar No. 1	N	1,218	1,177	4-90	1992
Tennessee Valley Authority	Watts Bar No. 2	N	1,218	1,177	10-91	1996
Texas Utilities Company System	Comanche Peak No. 2	N	1,161	1,150	1-90	6-91
Total Nuclear Units Delayed One Year or More		[5]	6,033	5,930		
Total Nuclear Units Removed from Schedule and Delayed		[5]	6,033	5,930		
Arizona Public Service Company	Cholla No. 5	F	375	340	2005	Removed
Brazos Electric Power Corp	San Miguel No. 2	F	409	400	1-96	Removed
Pacific Gas & Electric Company	Geysers No. 21	F	168	140	11-91	Removed
Salt River Project	Coronado No. 3	F	417	350	1999	Removed
Total Fossil Units Removed from Schedule		[4]	1,369	1,230		
Public Service Company of Colorado	Pawnee No. 2	F	508	485	5-96	4-98
Tucson Electric Power Company	Springerville No. 2	F	350	360	6-89	6-90
Total Fossil Units Delayed One Year or More		[2]	858	845		
Total Fossil Units Removed from Schedule and Delayed		[6]	2,227	2,075		
Total Nuclear and Fossil Units Removed From Schedule and Delayed		[11]	8,260	8,005		

ADDITIONS TO ELECTRIC GENERATING CAPABILITY DURING 1988

The 1988 additions to electric generating capability in the contiguous United States are shown in the top part of Table 7 according to the type of generating units. The second portion of the table presents the same information arranged according to the reliability councils in which the new capability was installed. The third portion of the table reports the same information classified according to ownership of the new units.

Table 7 -- 1988 ADDITIONS TO ELECTRIC GENERATING CAPABILITY (In Terms of Net Expected Capabilities of the Units)

	THERMAL								HYDRAULIC					
	Steam Turbine-Generators				Combustion Turbine-Generators		Diesel Engine-Generators		Conventional		Pumped-Storage		Total	
	Nuclear		Conventional											
	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW
1988 ADDITIONS	5	5,813	4	1,031	9	585	-	-	3	40	-	-	21	7,469
ADDITIONS BY REGION														
NPCC	1	1,080	-	-	-	-	-	-	-	-	-	-	1	1,080
MAAC	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ECAR	1	1,093	-	-	-	-	-	-	2	34	-	-	3	1,127
SERC	-	-	1	499	-	-	-	-	-	-	-	-	1	499
MAIN	1	1,120	-	-	-	-	-	-	-	-	-	-	1	1,120
SPP	-	-	-	-	-	-	-	-	1	6	-	-	1	6
ERCOT	1	1,250	1	400	9	585	-	-	-	-	-	-	11	2,235
MAPP	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WSCC	1	1,270	2	132	-	-	-	-	-	-	-	-	3	1,402
ADDITIONS BY OWNERSHIP														
Investor-Owned	5	5,813	-	-	9	585	-	-	-	-	-	-	14	6,398
Federal	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Municipal	-	-	1	499	-	-	-	-	2	34	-	-	3	533
Cooperative	-	-	-	-	-	-	-	-	1	6	-	-	1	6
State and Local	-	-	3	532	-	-	-	-	-	-	-	-	3	532

Table 8 - 1988 ADDITIONS TO ELECTRIC GENERATING CAPABILITY
U.S. Electric Utility Systems
Units 4,000 kW and Larger

LEGEND FOR LISTING OF PROJECTS PLACED IN SERVICE

SYMBOLS:

Investor-Owned.....I
Federal.....F
Municipal.....M
Cooperative.....C
State & Local.....SL

Thermal

- Conventional steam turbine-generator.....T
- Nuclear steam turbine-generator.....N
- Combustion turbine-generator.....G
- Diesel engine-generator.....D

Hydraulic

- Hydraulic turbine-generator.....H

Pumped-Storage

- Pumped-storage turbine-generator.....S
- Reversible pumped-storage turbine-generator.....R

Combined-Cycle

- Combustion turbine-generator for combined-cycle operation.....GC
- Conventional steam turbine-generator for combined-cycle operation.....TC

+ Denotes multiple ownership of the unit. In such cases, the name of the participating power system in whose service area the installation will be located is shown. In case the location does not fall within the service area of any of the participants, the name of the power system shown is the first in alphabetical order among the major participants.

NOTE: Megawatts shown for individual generating units represent, in most cases, the net operating capability expected by the utility systems; in other cases they represent the manufacturer's nameplate rating of the unit.

Table 8 1988 ADDITIONS TO ELECTRIC GENERATING CAPABILITY BY U.S. ELECTRIC UTILITY SYSTEMS

REGIONS		SYSTEM	UNIT	OWNER-SHIP	TYPE	FOSSIL FUELS	MW of NET EXPECTED CAPABILITY
NPCC	+	NIAGARA MOHAWK POWER CORP	NINE MILE POINT NO 2	I	N		1,080
ECAR		DETROIT EDISON COMPANY	FERMI NO 2	I	N		1,093
ECAR		NEW MARTINSVILLE WEST VA	HANNIBAL LOCK & DAM	M	H		17
ECAR		NEW MARTINSVILLE WEST VA	HANNIBAL LOCK & DAM	M	H		17
SERC	+	JACKSONVILLE FLORIDA	ST JOHNS RIVER PARK NO 2	M	T	Coal	499
MAIN		COMMONWEALTH EDISON CO	BRAIDWOOD NO 2	I	N		1,120
SPP		ARKANSAS ELECTRIC COOP	LOCK & DAM NO 13 NO 1	C	H		6
ERCOT	+	HOUSTON LIGHTING & POWER CO	SOUTH TEXAS NO 1	I	N		1,250
ERCOT	+	LOWER COLORADO RIVER AUTHY	FAYETTE NO 3	SL	T	Coal	400
ERCOT		TEXAS UTILITIES COMPANY	MORGAN CREEK NO 1	I	G		65
ERCOT		TEXAS UTILITIES COMPANY	MORGAN CREEK NO 2	I	G		65
ERCOT		TEXAS UTILITIES COMPANY	MORGAN CREEK NO 3	I	G		65
ERCOT		TEXAS UTILITIES COMPANY	MORGAN CREEK NO 4	I	G		65
ERCOT		TEXAS UTILITIES COMPANY	MORGAN CREEK NO 5	I	G		65
ERCOT		TEXAS UTILITIES COMPANY	MORGAN CREEK NO 6	I	G		65
ERCOT		TEXAS UTILITIES COMPANY	PERMIAN BASIN NO 1	I	G		65
ERCOT		TEXAS UTILITIES COMPANY	PERMIAN BASIN NO 2	I	G		65
ERCOT		TEXAS UTILITIES COMPANY	PERMIAN BASIN NO 3	I	G		65
WSCC		ARIZONA PUBLIC SERVICE CO	PALO VERDE NO 3	I	N		1,270
WSCC		CENTRAL CAL POWER AGENCY	COLDWATER NO 1	SL	T	Geothermal	66
WSCC		CENTRAL CAL POWER AGENCY	COLDWATER NO 2	SL	T	Geothermal	66

21 GENERATING UNITS WERE ADDED WITH TOTAL NET EXPECTED CAPABILITY OF 7,469 MW

NUCLEAR ELECTRIC POWER GENERATING UNITS IN COMMERCIAL OPERATION

No steam turbine-generators for nuclear projects have been ordered since 1976, and no nuclear steam supply systems (reactors) since 1978. As of January 1, 1989, nuclear capacity accounts for 46 percent of the aggregate of the industry's scheduled expansion program.

Table 9 shows subtotals of the amount of nuclear megawatts placed in service each year. As of January 1, 1989, there were 108 nuclear units in commercial operation with an aggregate winter rating of 95,792 megawatts. There were five additions to nuclear generating capacity during 1988. Two decommisioned units have been removed from the list.

Table 9 – NUCLEAR POWER UNITS IN OPERATION IN THE CONTIGUOUS U.S. as of January 1, 1989

	SYSTEM	UNIT NAME & NO.	YEAR PLACED IN COMML OPTN	SUMMER	WINTER	ANN SUBTTLS OF SUMMER MW RATINGS
1.	Yankee Atomic Electric Company	Yankee Rowe	1961	175	176	175
2.	Consumers Power Company	Big Rock Point	1962	63	63	63
3.	Conn Yankee Atomic Power Company	Haddam Neck	1968	555	580	
4.	SoCal Edison & San Diego G & E Co.	San Onofre No. 1	1968	436	436	991
5.	GPU Nuclear Corporation	Oyster Creek No. 1	1969	620	650	
6.	Niagara Mohawk Power Corp.	Nine Mile Point No. 1	1969	610	610	
7.	Rochester Gas & Electric Corp.	R. E. Ginna	1969	470	470	1,700
8.	Northeast Utilities	Millstone Point No. 1	1970	654	660	
9.	Wisconsin Electric Power Company	Point Beach No. 1	1970	495	495	1,149
10.	Carolina Power & Light Company	H. B. Robinson	1971	665	700	
11.	Commonwealth Edison Company	Dresden No. 2	1971	772	794	
12.	Northern States Power Company	Monticello No. 1	1971	536	557	1,973
13.	Boston Edison Company	Pilgrim No. 1	1972	670	670	
14.	Commonwealth Edison Company	Quad Cities No. 1	1972	768	789	
15.	Commonwealth Edison Company	Quad Cities No. 2	1972	769	789	
16.	Florida Power & Light Company	Turkey Point No. 3	1972	666	696	
17.	Maine Yankee Atomic Power Company	Maine Yankee	1972	814	830	
18.	Vermont Yankee N. Power Corp.	Vermont Yankee	1972	496	528	
19.	Virginia Electric & Power Company	Surry No. 1	1972	775	775	4,958
20.	Commonwealth Edison Company	Dresden No. 3	1973	773	794	
21.	Consumers Power Company	Palisades No. 1	1973	635	740	
22.	Duke Power Company	Oconee No. 1	1973	860	860	
23.	Duke Power Company	Oconee No. 2	1973	860	860	
24.	Florida Power & Light Company	Turkey Point No. 4	1973	666	696	
25.	Northern States Power Company	Prairie Island No. 1	1973	503	523	
26.	Omaha Public Power District	Fort Calhoun No. 1	1973	439	457	
27.	Tennessee Valley Authority	Browns Ferry No. 1	1973	1,067	1,067	
28.	Virginia Electric & Power Company	Surry No. 2	1973	775	775	
29.	Wisconsin Electric Power Company	Point Beach No. 2	1973	495	495	7,073
30.	Arkansas Power & Light Company	Arkansas Nuclear No. 1	1974	836	836	
31.	Commonwealth Edison Company	Zion No. 1	1974	1,040	1,040	
32.	Commonwealth Edison Company	Zion No. 2	1974	1,040	1,040	
33.	Consolidated Edison Co. of NY	Indian Point No. 2	1974	849	864	
34.	Duke Power Company	Oconee No. 3	1974	860	860	

Table 9 - NUCLEAR POWER UNITS IN OPERATION IN THE CONTIGUOUS U.S. as of January 1, 1989 -- Cont'd.

	SYSTEM	UNIT NAME & NO.	YEAR PLACED IN COMML OPTN	SUMMER	WINTER	ANN SUBTTLS OF SUMMER MW RATINGS
36.	Iowa Electric Light & Power Co.	Duane Arnold	1974	480	510	
37.	Nebraska Public Power District	Cooper	1974	778	778	
38.	Northern States Power Company	Prairie Island No. 2	1974	500	520	
39.	Philadelphia Electric Company	Peach Bottom No. 2	1974	1,051	1,055	
40.	Philadelphia Electric Company	Peach Bottom No. 3	1974	1,035	1,035	
41.	Wisconsin Public Service Corp.	Kewaunee No. 1	1974	525	517	9,770
42.	Baltimore Gas & Electric Company	Calvert Cliffs No. 1	1975	810	820	
43.	Carolina Power & Light Company	Brunswick No. 2	1975	790	790	
44.	Georgia Power Company	Hatch No. 1	1975	771	771	
45.	Indiana & Michigan Electric Co.	D. C. Cook No. 1	1975	1,050	1,050	
46.	New York Power Authority	J. A. Fitzpatrick	1975	821	821	
47.	Sacramento Utility District	Rancho Seco No. 1	1975	875	903	
48.	Tennessee Valley Authority	Browns Ferry No. 2	1975	1,067	1,067	6,184
49.	Duquesne Light Company	Beaver Valley No. 1	1976	800	800	
50.	Florida Power & Light Company	St. Lucie No. 1	1976	777	795	
51.	New York Power Authority	Indian Point No. 3	1976	965	965	
52.	Northeast Utilities	Millstone Point No. 2	1976	864	864	
53.	Portland General Electric Company	Trojan	1976	1,080	1,080	4,486
54.	Alabama Power Company	J. M. Farley No. 1	1977	807	807	
55.	Baltimore Gas & Electric Company	Calvert Cliffs No. 2	1977	825	860	
56.	Carolina Power & Light Company	Brunswick No. 1	1977	790	790	
57.	Florida Power Corporation	Crystal River No. 3	1977	782	807	
58.	Public Service Elec & Gas Company	Salem No. 1	1977	1,079	1,100	
59.	Tennessee Valley Authority	Browns Ferry No. 3	1977	1,067	1,067	
60.	Toledo Edison Company	Davis-Besse No. 1	1977	906	906	6,256
61.	Indiana & Michigan Electric Co.	D. C. Cook No. 2	1978	1,100	1,100	
62.	Virginia Electric & Power Company	North Anna No. 1	1978	898	907	1,998
63.	Georgia Power Company	Hatch No. 2	1979	771	771	
64.	Public Service Co. of Colorado	Fort St. Vrain	1979	200	200	971
65.	Arkansas Power & Light Company	Arkansas Nuclear No. 2	1980	858	858	
66.	Virginia Electric & Power Company	North Anna No. 2	1980	870	870	1,728
67.	Alabama Power Company	J. M. Farley No. 2	1981	812	812	
68.	Duke Power Company	McGuire No. 1	1981	1,180	1,180	
69.	Public Service Elec & Gas Company	Salem No. 2	1981	1,106	1,120	
70.	Tennessee Valley Authority	Sequoyah No. 1	1981	1,128	1,128	4,226
71.	Tennessee Valley Authority	Sequoyah No. 2	1982	1,148	1,148	1,148
72.	Florida Power & Light Company	St. Lucie No. 2	1983	802	802	
73.	Pennsylvania Power & Light Company	Susquehanna No. 1	1983	1,050	1,050	
74.	SoCal Edison & San Diego G & E	San Onofre No. 2	1983	1,070	1,070	2,922

Table 9 – NUCLEAR POWER UNITS IN OPERATION IN THE CONTIGUOUS U.S. as of January 1, 1989 -- Cont'd.

	SYSTEM	UNIT NAME & NO.	YEAR PLACED IN COMML OPTN	SUMMER	WINTER	ANN SUBTTLS OF SUMMER MW RATINGS
75.	Commonwealth Edison Company	LaSalle County No. 1	1984	1,048	1,078	
76.	Commonwealth Edison Company	LaSalle County No. 2	1984	1,048	1,078	
77.	Duke Power Company	McGuire No. 2	1984	1,150	1,150	
78.	SoCal Edison & San Diego G & E Co.	San Onofre No. 3	1984	1,080	1,080	
79.	South Carolina Electric & Gas Co.	Summer No. 1	1984	885	885	
80.	Union Electric Company	Callaway No. 1	1984	1,109	1,123	
81.	Washington Pub Power Supply System	WPPSS No. 2	1984	1,100	1,100	7,420
82.	Commonwealth Edison Company	Byron No. 1	1985	1,120	1,120	
83.	Duke Power Company	Catawba No. 1	1985	1,145	1,145	
84.	Kansas Gas & Electric Company	Wolf Creek No. 1	1985	1,150	1,150	
85.	Louisiana Power & Light Company	Waterford No. 3	1985	1,104	1,104	
86.	Mississippi Power & Light Company	Grand Gulf No. 1	1985	1,250	1,250	
87.	Pacific Gas & Electric Company	Diablo Canyon No. 1	1985	1,073	1,073	
88.	Pennsylvania Power & Light Company	Susquehanna No. 2	1985	1,050	1,050	7,892
89.	Arizona Public Service Company	Palo Verde No. 1	1986	1,270	1,270	
90.	Arizona Public Service Company	Palo Verde No. 2	1986	1,270	1,270	
91.	Duke Power Company	Catawba No. 2	1986	1,145	1,145	
92.	Gulf States Utilities Company	River Bend No. 1	1986	937	937	
93.	Northeast Utilities	Millstone Point No. 3	1986	1,142	1,150	
94.	Pacific Gas & Electric Company	Diablo Canyon No. 2	1986	1,105	1,105	
95.	Philadelphia Electric Company	Limerick No. 1	1986	1,055	1,065	
96.	Public Service Electric & Gas Co.	Hope Creek No. 1	1986	1,014	1,014	8,938
97.	Carolina Power & Light Company	Shearon Harris No. 1	1987	860	860	
98.	Cleveland Electric Illuminating Co.	Perry No. 1	1987	1,183	1,205	
99.	Commonwealth Edison Company	Braidwood No. 1	1987	1,090	1,120	
100.	Commonwealth Edison Company	Byron No. 2	1987	1,120	1,120	
101.	Duquesne Light Company	Beaver Valley No. 2	1987	820	833	
102.	Georgia Power Company	Vogtle No. 1	1987	1,086	1,086	
103.	Illinois Power Company	Clinton No. 1	1987	933	944	7,092
104.	Arizona Public Service Company	Palo Verde No. 3	1988	1,270	1,270	
105.	Commonwealth Edison Company	Braidwood No. 2	1988	1,090	1,120	
106.	Detroit Edison Company	Enrico Fermi No. 2	1988	1,093	1,093	
107.	Houston Lighting & Power Company	South Texas No. 1	1988	1,250	1,250	
108.	Niagara Mohawk Power Corp.	Nine Mile Point No. 2	1988	1,080	1,080	5,783
		108 Nuclear units totaling		94,896	95,792	
				SUMMER MW	WINTER MW	

PART II. ELECTRIC POWER SUPPLY 1989-1998

SUMMER CAPABILITIES, PEAK LOADS, AND PERCENT CAPACITY MARGINS

Summer peak capabilities, peak loads, and percent capacity margins as now forecast for the years 1989 through 1998 are shown in Table 10, page 19. Similar information for winter is shown in Table 11, page 21.

SUMMER CAPABILITIES

Preliminary figures published in the 1988 POST-SUMMER ELECTRIC POWER SURVEY indicated that the 1988 capability at time of summer peak was 1.8 percent above 1987. According to final data now available, the actual increase was 2.1 percent.

The overall pattern of the newly projected summer capability values generally shows reductions in the near years and increases in the more distant years when compared with the projections for the same years 12 months ago. For the nine regions taken together, 1989 shows a reduction of 0.7 percent; increases start in 1992, reaching a plus 0.7 percent by 1995.

The 1998 summer capability for the sum of the nine regions is projected at 738.1 thousand megawatts. This represents an average annual increase of 1.2 percent between the first and tenth forecast years.

SUMMER PEAK LOADS

Summer peak load forecasts have been increased by seven of the nine reliability councils. ERCOT decreased its projections throughout the period and MAAC reduced its load projections from 1995 on. For the nine regions taken together, peak loads range from 2.1 percent higher for 1989 to 2.5 percent higher in 1997, compared with values shown for those years in the 1987 ELECTRIC POWER ANNUAL REPORT. The summer peak load for the sum of the nine regions, which was 529.5 thousand megawatts in 1988, is projected to be 521.9 thousand megawatts in 1988, a decrease of 1.4 percent. For the summer of 1998, the projection is 622.8 thousand megawatts. This represents an average annual increase of 2.0 percent between the first and tenth forecast years.

SUMMER PERCENT CAPACITY MARGINS

Of the 81 summer capacity margin percentages shown for the nine-year period 1989-1997 for the nine reliability councils, 67 of the values are lower than the equivalent respective values one year previous, and only 14 of the percent margins are higher. MAAC and ERCOT show higher percent margins throughout most of the period. Summer percent capacity margins for the country as a whole are lower throughout the period. As now forecast, the summer capacity margins for the country range from 21.2 percent in 1990 to 15.6 percent in 1998, shown in these reports for the first time.

Table 10 - SUMMER CAPABILITIES, PEAK LOADS, INSTALLED MARGINS & PERCENT CAPACITY MARGINS -- 1989-1998 PROJECTED (Megawatts)

Regions		1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Growth Rate 1989-1998*
NPCC	Capability	56,512	59,880	62,550	62,576	62,701	62,411	63,153	64,020	64,001	64,006	1.4%
	Peak Load	46,836	48,047	49,311	50,451	51,587	52,662	53,770	54,827	55,816	56,764	..2%
	Installed Margin	9,676	11,833	13,239	12,125	11,114	9,749	9,383	9,193	8,185	7,242	
	% Capacity Margin	17.1%	19.8%	21.2%	19.4%	17.7%	15.6%	14.9%	14.4%	12.8%	11.3%	
MAAC	Capability	50,040	51,718	52,897	54,630	55,371	56,212	56,437	57,076	57,849	58,283	1.7%
	Peak Load	41,565	42,236	42,888	43,547	44,235	44,907	45,418	46,122	46,801	47,365	1.5%
	Installed Margin	8,475	9,482	10,009	11,083	11,136	11,305	11,019	10,954	11,048	10,918	
	% Capacity Margin	16.9%	18.3%	18.9%	20.3%	20.1%	20.1%	19.5%	19.2%	19.1%	18.7%	
ECAR	Capability	92,713	96,795	99,569	100,041	100,948	101,584	102,396	103,548	104,514	104,881	1.4%
	Peak Load	75,589	76,977	78,396	79,685	81,021	82,292	83,658	85,018	86,416	87,694	1.7%
	Installed Margin	17,124	19,818	21,173	20,356	19,927	19,292	18,738	18,530	18,098	17,187	
	% Capacity Margin	18.5%	20.5%	21.3%	20.3%	19.7%	19.0%	18.3%	17.9%	17.3%	16.4%	
SERC	Capability	140,228	142,825	145,514	148,689	152,382	155,071	158,119	161,666	163,235	166,380	1.9%
	Peak Load	115,888	120,346	122,967	126,315	129,353	132,320	135,551	138,966	142,256	145,368	2.6%
	Installed Margin	24,340	22,479	22,547	22,374	23,029	22,751	22,568	22,700	20,979	21,012	
	% Capacity Margin	17.4%	15.7%	15.5%	15.0%	15.1%	14.7%	14.3%	14.0%	12.9%	12.6%	
MAIN	Capability	48,355	48,571	48,903	48,917	49,337	49,474	49,670	49,811	49,869	50,495	0.5%
	Peak Load	38,415	38,967	39,605	40,235	40,855	41,513	42,166	42,825	43,479	44,181	1.6%
	Installed Margin	9,940	9,604	9,298	8,682	8,482	7,961	7,504	6,986	6,390	6,314	
	% Capacity Margin	20.6%	19.8%	19.0%	17.7%	17.2%	16.1%	15.1%	14.0%	12.8%	12.5%	
SPP	Capability	65,666	66,070	66,619	66,503	66,741	66,909	67,451	67,673	68,098	68,636	0.5%
	Peak Load	49,430	50,664	51,798	52,812	53,799	54,831	55,928	57,014	58,173	59,295	2.0%
	Installed Margin	16,236	15,406	14,821	13,691	12,942	12,078	11,523	10,659	9,925	9,341	
	% Capacity Margin	24.7%	23.3%	22.2%	20.6%	19.4%	18.1%	17.1%	15.8%	14.6%	13.6%	
ERCOT	Capability	51,669	52,942	52,904	54,252	54,728	55,211	55,441	56,209	58,166	58,953	1.5%
	Peak Load	41,169	41,550	42,840	43,753	45,049	46,004	46,515	47,601	48,939	50,085	2.2%
	Installed Margin	10,500	11,392	10,064	10,499	9,679	9,207	8,926	8,608	9,227	8,868	
	% Capacity Margin	20.3%	21.5%	19.0%	19.4%	17.7%	16.7%	16.1%	15.3%	15.9%	15.0%	
MAPP	Capability	30,958	30,959	31,040	31,223	31,767	31,771	32,066	32,288	32,564	33,055	0.7%
	Peak Load	23,796	24,174	24,527	24,897	25,269	25,670	26,114	26,568	27,037	27,494	1.6%
	Installed Margin	7,162	6,785	6,513	6,326	6,498	6,101	5,952	5,720	5,527	5,561	
	% Capacity Margin	23.1%	21.9%	21.0%	20.3%	20.5%	19.2%	18.6%	17.7%	17.0%	16.8%	
WSCC	Capability	125,224	127,683	128,838	129,520	130,133	131,077	131,773	131,662	132,707	133,372	0.7%
	Peak Load	89,247	91,159	92,419	93,965	95,567	97,020	98,685	100,514	102,475	104,508	1.8%
	Installed Margin	35,977	36,524	36,419	35,555	34,566	34,057	33,088	31,148	30,232	28,864	
	% Capacity Margin	28.7%	28.6%	28.3%	27.5%	26.6%	26.0%	25.1%	23.7%	22.8%	21.6%	
NERC UNITED STATES**	Capability	661,365	677,443	688,834	696,351	704,108	709,720	716,506	723,953	731,003	738,061	1.2%
	Peak Load	521,935	534,120	544,751	555,660	566,735	577,219	587,805	599,455	611,392	622,754	2.0%
	Installed Margin	139,430	143,323	144,083	140,691	137,373	132,501	128,701	124,498	119,611	115,307	
	% Capacity Margin	21.1%	21.2%	20.9%	20.2%	19.5%	18.7%	18.0%	17.2%	16.4%	15.6%	

* Compound annual growth rate from 1989 to 1998.

** U.S. totals are not meaningful and should not be used for policy purposes.

NOTE: For definitions of terms see page 5.

WINTER CAPABILITIES, PEAK LOADS, AND PERCENT CAPACITY MARGINS

WINTER CAPABILITIES

Winter 1989/90 capability now projected for the entire electric utility industry is 680.7 thousand megawatts. The regional winter capability values shown in this report for 1989/90 through 1997/98 generally show a pattern of reductions in the first three years changing to increases in the more distant years. SPP and MAPP are the only reliability councils that have increased their winter capability projections over the whole period. MAAC and WSCC also project higher values from the early nineties on. For the nine regions taken together, changes range from reductions of 0.3 percent in 1989 and 1990 to an increase of 0.8 percent in 1997/98.

For winter 1997/98 the total capability of the industry is projected to reach 738.6 thousand megawatts. This value yields an average annual compound growth rate of 1.1 percent between the first and tenth forecast years.

The scheduled additions table on page 25 summarizes the number and aggregate ratings of planned electric generating units that as of January 1, 1989 had been both ordered from the equipment manufacturers and placed in the expansion program by being assigned official scheduled dates of commercial operation by the utilities. As of the turn of 1988/89, the furthest out year for which an ordered unit had been scheduled for operation was 2005.

WINTER PEAK LOADS

As now projected, the winter 1988/89 peak load for the contiguous U.S. is expected to be 456.5 thousand megawatts, an increase of 1.8 percent over the winter 1987/88 peak load. The new projections for eight of the nine regions show increased values throughout the period. ERCOT is the only region that decreased its winter peak load projec- tions. The total of the nine regions shows increases in the range of 1.9 to 2.7 percent above the winter peak loads expected for these years twelve months ago.

For winter 1998/99, the furthest out year projected in this report, the expected peak load is 573.2 thousand megawatts. This represents an average annual increase of 2.1 percent between the first and tenth forecast years.

WINTER PERCENT CAPACITY MARGINS

Compared with projected percent capacity margin values calculated on the same basis one year ago, ERCOT and MAPP winter percent margins reported in this survey are consistently higher. The other seven regions all show reduced margins. For the country as a whole, percent capacity margins are now projected to range from 30.1 percent for the winter of 1989/90 to 23.7 percent for 1998/99.

Table 11 - WINTER CAPABILITIES, PEAK LOADS, INSTALLED MARGINS & PERCENT CAPACITY MARGINS -- 1988-1998 PROJECTED (Megawatts)

Regions		1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	Growth Rate 1989-1998*
NPCC	Capability	59,033	61,407	61,650	62,170	62,158	62,030	62,767	63,634	63,561	63,554	0.8%
	Peak Load	44,954	46,269	47,113	47,938	48,727	49,735	50,687	51,612	52,457	53,527	2.0%
	Installed Margin	14,079	15,138	14,537	14,232	13,431	12,295	12,080	12,022	11,104	10,027	
	% Capacity Margin	23.8%	24.7%	23.6%	22.9%	21.6%	19.8%	19.2%	18.9%	17.5%	15.8%	
MAAC	Capability	52,659	54,630	55,684	57,207	58,152	58,847	59,132	59,918	60,873	61,454	1.7%
	Peak Load	36,980	37,806	38,621	39,485	40,392	41,239	42,118	43,008	43,864	44,691	2.1%
	Installed Margin	15,679	16,824	17,063	17,722	17,760	17,608	17,014	16,910	17,009	16,763	
	% Capacity Margin	29.8%	30.8%	30.6%	31.0%	30.5%	29.9%	28.8%	28.2%	27.9%	27.3%	
ECAR	Capability	97,370	99,016	101,154	101,639	102,451	103,675	104,292	105,367	106,092	106,638	1.0%
	Peak Load	72,412	73,700	75,039	76,395	77,657	79,034	80,445	81,824	83,122	84,483	1.7%
	Installed Margin	24,958	25,316	26,115	25,244	24,794	24,641	23,847	23,543	22,970	22,155	
	% Capacity Margin	25.6%	25.6%	25.8%	24.8%	24.2%	23.8%	22.9%	22.3%	21.7%	20.8%	
SERC	Capability	143,339	145,241	147,638	152,057	154,551	158,580	161,702	164,027	166,742	168,733	1.8%
	Peak Load	114,642	117,399	120,765	124,182	127,506	130,874	134,208	137,605	140,524	143,956	2.6%
	Installed Margin	28,697	27,842	26,873	27,875	27,045	27,706	27,494	26,422	26,218	24,777	
	% Capacity Margin	20.0%	19.2%	18.2%	18.3%	17.5%	17.5%	17.0%	16.1%	15.7%	14.7%	
MAIN	Capability	49,028	49,511	49,543	49,705	50,033	50,291	50,412	50,447	50,180	51,322	0.5%
	Peak Load	30,835	31,419	31,945	32,511	33,141	33,774	34,390	35,015	35,677	36,331	1.8%
	Installed Margin	18,193	18,092	17,598	17,194	16,892	16,517	16,022	15,432	14,503	14,991	
	% Capacity Margin	37.1%	36.5%	35.5%	34.6%	33.8%	32.8%	31.8%	30.6%	28.9%	29.2%	
SPP	Capability	66,439	66,386	66,690	66,465	66,965	67,465	67,974	68,050	68,049	69,053	0.4%
	Peak Load	37,041	38,060	38,992	39,779	40,654	41,572	42,535	43,514	44,521	45,505	2.3%
	Installed Margin	29,398	28,326	27,698	26,686	26,311	25,893	25,439	24,536	23,528	23,548	
	% Capacity Margin	44.2%	42.7%	41.5%	40.2%	39.3%	38.4%	37.4%	36.1%	34.6%	34.1%	
ERCOT	Capability	52,653	53,268	54,331	54,905	54,601	55,266	56,094	57,096	58,645	59,697	1.4%
	Peak Load	33,092	33,946	34,890	36,281	37,275	37,807	38,887	40,155	41,328	42,264	2.8%
	Installed Margin	19,561	19,322	19,441	18,624	17,326	17,459	17,207	16,941	17,317	17,433	
	% Capacity Margin	37.2%	36.3%	35.8%	33.9%	31.7%	31.6%	30.7%	29.7%	29.5%	29.2%	
MAPP	Capability	30,963	31,252	31,271	31,623	32,519	32,550	32,888	32,985	33,135	33,821	1.0%
	Peak Load	20,317	20,709	21,065	21,407	21,722	22,075	22,449	22,862	23,249	23,642	1.7%
	Installed Margin	10,646	10,543	10,206	10,216	10,797	10,475	10,439	10,123	9,886	10,179	
	% Capacity Margin	34.4%	33.7%	32.6%	32.3%	33.2%	32.2%	31.7%	30.7%	29.8%	30.1%	
WSCC	Capability	129,188	130,845	131,707	132,263	133,231	134,415	135,375	136,819	137,499	137,363	0.7%
	Peak Load	85,256	86,440	87,622	89,056	90,711	92,176	93,939	95,723	97,486	98,771	1.6%
	Installed Margin	43,932	44,405	44,085	43,207	42,520	42,239	41,436	41,096	40,013	38,592	
	% Capacity Margin	34.0%	33.9%	33.5%	32.7%	31.9%	31.4%	30.6%	30.0%	29.1%	28.1%	
NERC UNITED STATES**	Capability	680,672	691,556	699,668	708,034	714,661	723,119	730,636	738,343	744,776	751,635	1.1%
	Peak Load	475,529	485,748	496,052	507,034	517,785	528,286	539,658	551,318	562,228	573,170	2.1%
	Installed Margin	205,143	205,808	203,616	201,000	196,876	194,833	190,978	187,025	182,548	178,465	
	% Capacity Margin	30.1%	29.8%	29.1%	28.4%	27.5%	26.9%	26.1%	25.3%	24.5%	23.7%	

* Compound annual growth rate from 1988/89 to 1997/98

** U.S. totals are not meaningful and should not be used for policy purposes.

NOTE: For definitions of terms see page 5.

RELATIONSHIP BETWEEN SUMMER AND WINTER PEAK LOADS, 1989-1998

The relationship between the summer and winter peak loads in the different regions of the country, and also for the sum of the U.S. portions of the NERC regions, are shown in the accompanying table, where the summer peak load in case is expressed as a percentage of the winter peak load for the following season.

Though there are some changes from year to year in the regional ratios, the movements are generally offsetting to the extent that the summer/winter ratio for the sum of the nine regions calculates to either 110 percent or 109 percent throughout the ten-year period.

Table 12 - SUMMER PEAK LOADS AS PERCENT OF PEAK LOADS FOR THE FOLLOWING WINTER, 1989-1998

Regions	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99
NPCC	104	104	105	105	106	106	106	106	106	106
MAAC	112	112	111	110	110	109	108	107	107	106
ECAR	104	104	104	104	104	104	104	104	104	104
SERC	101	103	102	102	101	101	101	101	101	101
MAIN	125	124	124	124	123	123	123	122	122	122
SPP	133	133	133	133	132	132	131	131	131	130
ERCOT	124	122	123	121	121	122	120	119	118	119
MAPP	117	117	116	116	116	116	116	116	116	116
WSCC	105	105	105	106	105	105	105	105	105	106
NERC U.S.	110	110	110	110	109	109	109	109	109	109

Table 13 - ANNUAL PERCENT LOAD FACTORS, 1989-1998

Regions	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
NPCC	62.0	61.8	61.7	61.3	61.1	61.0	60.9	60.6	60.6	60.5
MAAC	60.1	60.4	60.8	60.9	61.2	61.5	61.9	61.9	62.2	62.5
ECAR	65.0	65.1	64.9	64.7	64.7	64.7	64.6	64.4	64.5	64.4
SERC	60.1	59.7	59.7	59.6	59.9	60.0	60.0	59.8	60.0	60.0
MAIN	56.7	56.9	57.0	56.9	57.2	57.2	57.3	57.2	57.5	57.5
SPP	55.0	54.8	54.6	54.6	54.7	54.8	54.7	54.7	54.9	55.0
ERCOT	56.2	56.8	56.5	56.5	56.8	56.7	56.9	56.9	57.2	57.4
MAPP	57.3	57.7	57.8	58.0	58.4	58.6	58.8	58.8	59.1	59.2
WSCC	68.7	68.5	68.6	68.4	68.5	68.6	68.6	68.5	68.6	68.5
NERC U.S.	61.3	61.2	61.2	61.1	61.2	61.3	61.3	61.2	61.4	61.4

ANNUAL ENERGY REQUIREMENTS AND ANNUAL PERCENT LOAD FACTORS FOR 1989–1998

Calendar-year energy requirements by NERC region and for the sum of the U.S. portions of the NERC regions are shown in Table 14. The corresponding annual load factors are given in Table 13. The energy requirement represents utility generation plus megawatthours received from all outside sources, including net imports from other countries and energy from certain industrial installations which are interconnected and coordinated with the utility systems.

The present projections of energy requirements for the contiguous United States for the years 1989 through 1997 range between 1.9 and 2.4 percent above the values predicted in the 1987 ELECTRIC POWER ANNUAL REPORT. MAAC raised its energy projections the most, between 3.4 and 4.4 percent higher over the period. SERC projections were 2.2 to 3.7 percent higher, ECAR 2.1 to 3.2 percent higher, NPCC 2.2 to 3.0 percent higher. MAPP was 0.6 to 2.7 percent higher, SPP 1.5 to 2.4 percent higher, and WSCC 1.9 to 2.7 higher. ERCOT was the only region showing reductions, ranging from 1.4 percent lower in 1989 to 4.8 percent lower in 1997. For 1998, the new furthest out year, the projected megawatthour requirement is 3.3 billion megawatthours. This represents an average annual increase of 2.0 percent between the first and tenth forecast years.

Table 14 ANNUAL ENERGY REQUIREMENTS (Megawatthours in Thousands) -- 1989–1998

Regions	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	Growth Rate 1989–1998*
NPCC	254,540	260,262	266,307	271,441	276,161	281,357	286,727	291,732	296,316	301,044	1.9%
MAAC	218,772	223,546	228,604	232,886	237,123	241,774	246,104	250,705	255,088	259,306	1.9%
ECAR	430,377	439,118	445,789	452,652	459,313	466,098	473,205	480,621	488,029	494,737	1.6%
SERC	610,556	629,185	643,097	661,718	678,638	695,640	712,454	730,517	747,535	764,550	2.5%
MAIN	190,644	194,305	197,654	201,123	204,547	208,086	211,588	215,228	218,916	222,720	1.7%
SPP	237,963	243,403	247,959	253,091	257,821	263,068	268,215	274,063	279,859	285,543	2.0%
ERCOT	202,683	206,748	211,896	217,033	224,294	228,650	231,794	237,751	245,158	251,636	2.4%
MAPP	119,456	122,250	124,116	126,787	129,197	131,733	134,399	137,249	139,975	142,664	2.0%
WSCC	537,481	546,651	554,987	564,972	573,168	583,230	593,277	604,650	615,511	627,050	1.7%
NERC U.S.	2,802,472	2,865,468	2,920,409	2,981,703	3,040,262	3,099,636	3,157,763	3,222,516	3,286,387	3,349,250	2.0%

* Average annual growth rate from 1989 to 1998

FUTURE EXPANSION PROGRAM AND SCHEDULED STEAM TURBINE-GENERATOR ADDITIONS BY SIZE

Table 16 shows that as of January 1, 1989, the electric utility systems serving the contiguous United States had on order with both domestic and foreign manufacturers, and scheduled for commercial operation during 1989 and later years, a total of 32.6 thousand megawatts. This included seven hydro units of both conventional and pumped-storage type, totaling 1.0 thousand megawaits. The thermal units include thirteen nuclear steam turbine-generators, twenty-seven conventional steam turbine-generators, and thirty-two combustion turbine-generators. Some of this capacity is on site and being installed; the remainder is under manufacture or in the form of firm orders.

During 1989, 4 nuclear power units are scheduled for commercial operation. These 4 units have an aggregate capability of 4.3 thousand megawatts. As of January 1, 1989, there are 9 additional nuclear units on order and scheduled for commercial operation in 1990 and later in the contiguous United States, having an aggregate capability of 10.6 thousand megawatts. These units are included in the regional listing designated Table 17. An indeterminate number of units, amounting to several thousand megawatts, are also on order but are either awaiting their first assignment of a scheduled date of commercial operation by the utility systems, or were once scheduled and have since been removed from the expansion program. It is probable that the majority of the orders in the second category (being held open as options by the manufacturers) will not be reactivated.

Table 15 shows that, of the total 29.4 thousand megawatts of steam turbine-generators on order as of January 1, 1989, and scheduled for service, nuclear and conventional units in sizes 700 megawatts and larger account for 70.2 percent of the total. The units in the less than 100 megawatt range are comprised of five coal-fired steam turbine-generators with a total capability of 307 megawatts, two of which are for combined-cycle operation.

Table 15 - NUMBER AND AGGREGATE CAPABILITY OF STEAM TURBINE-GENERATORS IN THE EXPANSION PROGRAM GROUPED ACCORDING TO SIZE RANGE as of January 1, 1989

Size Range, MW	No. Of Units	Aggregate Capability MW	Percent of Total
1,300 MW and Larger	2	2,600	8.8
1,200 to 1,299	5	6,166	21.0
1,100 to 1,199	5	5,804	19.8
1,000 to 1,099	2	2,141	7.3
900 to 999	-	--	-
800 to 899	2	1,658	5.6
700 to 799	3	2,250	7.7
600 to 699	6	3,865	13.2
500 to 599	5	2,500	8.5
400 to 499	3	1,478	5.0
300 to 399	1	360	1.2
200 to 299	1	250	0.9
100 to 199	-	--	-
Under 100	5	307	1.0
TOTAL STEAM UNITS	40	29,379	100.0

Table 16 SCHEDULED ADDITIONS TO ELECTRIC GENERATING CAPABILITY BASED ON SCHEDULED DATES OF COMMERCIAL OPERATION AS OF JANUARY 1, 1989

In Terms of Net Expected Capability Ratings of the Units in Megawatts

	THERMAL								HYDRAULIC					
	Steam Turbine-Generators				Combustion Turbine-Generators		Diesel Engine-Generators		Conventional		Pumped-Storage		Total	
	Nuclear		Conventional											
	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW
TOTAL SCHEDULED	13	14,920	27	14,458	32	2,206	2	12	3	31	4	1,000	81	32,627
SCHEDULED ADDITIONS BY YEAR														
1989	4	4,295	4	2,874	17	1,036	2	12	1	6	-	-	28	8,223
1990	2	2,205	3	429	11	780	-	-	2	25	-	-	18	3,439
1991	1	1,150	4	2,712	3	265	-	-	-	-	4	1,000	12	5,127
1992	1	1,177	2	1,138	-	-	-	-	-	-	-	-	3	2,315
1993	-	-	1	90	-	-	-	-	-	-	-	-	1	90
1994	-	-	2	840	1	125	-	-	-	-	-	-	3	965
1995	-	-	1	750	-	-	-	-	-	-	-	-	1	750
1996	1	1,177	1	645	-	-	-	-	-	-	-	-	2	1,822
1997	-	-	1	750	-	-	-	-	-	-	-	-	1	750
1998	1	1,213	2	1,130	-	-	-	-	-	-	-	-	3	2,343
1999	3	3,703	5	2,500	-	-	-	-	-	-	-	-	8	6,203
2001	-	-	1	600	-	-	-	-	-	-	-	-	1	600
SCHEDULED ADDITIONS BY REGION														
NPCC	2	1,959	1	250	5	397	-	-	2	25	-	-	10	2,631
MAAC	1	1,055	1	640	8	691	2	12	-	-	-	-	12	2,398
ECAR	-	-	5	3,752	0	0	-	-	-	-	-	-	5	3,752
SERC	5	5,866	6	2,753	8	554	-	-	-	-	4	1,000	23	10,173
MAIN	-	-	-	-	0	0	-	-	-	-	-	-	-	-
SPP	-	-	-	-	2	86	-	-	-	-	-	-	2	86
ERCOT	3	3,550	6	4,038	6	390	-	-	-	-	-	-	15	7,978
MAPP	-	-	-	-	2	77	-	-	-	-	-	-	2	77
WSCC	2	2,490	8	3,025	1	11	-	-	1	6	-	-	12	5,532
SCHEDULED ADDITIONS BY OWNERSHIP														
INVESTOR-OWNED	7	7,650	23	12,802	27	2,024	-	-	2	25	4	1,000	63	23,501
FEDERAL	4	4,780	-	-	-	-	-	-	-	-	-	-	4	4,780
MUNICIPAL	-	-	2	556	4	171	2	12	1	6	-	-	9	745
COOPERATIVE	-	-	1	600	-	-	-	-	-	-	-	-	1	600
STATE AND LOCAL	2	2,490	1	500	1	11	-	-	-	-	-	-	4	3,001

Table 17 - SCHEDULED ADDITIONS TO ELECTRIC GENERATING CAPABILITY
Based on Scheduled Dates of Commercial Operation as of January 1, 1989

SYMBOLS:

Investor-Owned.....I
Federal.....F
Municipal.....M
Cooperative.....C
State & Local.....SL

Thermal

- Conventional steam turbine-generator.....T
- Nuclear steam turbine-generator....N
- Combustion turbine-generator.....G
- Diesel engine-generator.....D

Hydraulic

- Hydraulic turbine-generator.....H

Pumped-Storage

- Pumped-storage turbine-generator.....S
- Reversible pumped-storage turbine-generator.....R

Combined-Cycle

- Combustion turbine-generator for combined-cycle operation.....GC
- Conventional steam turbine-generator for combined-cycle operation.....TC

+ Denotes multiple ownership of the unit. In such cases, the name of the participating power system in whose service area the installation will be located is shown. In case the location does not fall within the service area of any of the participants, the name of the power system shown is the first in alphabetical order among the major participants.

o Denotes units added to the expansion program since July 1, 1988.

NOTE: Megawatts shown for individual generating units represent, in most cases, the net operating capability expected by the utility systems; in other cases they represent the manufacturer's nameplate rating of the unit.

TABLE 17 -- SCHEDULED ADDITIONS as of JANUARY 1, 1989

REGION	SYSTEM	UNIT	OWNER-SHIP	TYPE	STEAM FOSSIL FUELS	MW of NET EXPECTED CAPABILITY	SKED YEAR OPTN
NPCC	+ BOSTON EDISON COMPANY	OCEAN STATE PWR NO 1	I	TC	Gas	250	1991
NPCC	+ BOSTON EDISON COMPANY	OCEAN STATE PWR NO 1	I	GC		80	1991
NPCC	+ BOSTON EDISON COMPANY	OCEAN STATE PWR NO 2	I	GC		80	1991
NPCC	CENTRAL MAINE PR CO	MONTY NO 1	I	H		13	1990
NPCC	CENTRAL MAINE PR CO	MONTY NO 2	I	H		13	1990
NPCC	LONG ISLAND LTG CO	NEW YORK NO 1	I	G		79	1989
NPCC	LONG ISLAND LTG CO	NEW YORK NO 2	I	G		79	1989
NPCC	LONG ISLAND LTG CO	NEW YORK NO 3	I	G		79	1989
NPCC	LONG ISLAND LTG CO	SHOREHAM NO 1	I	N		809	1989
NPCC	+ PUB SERV CO NEW HAMP	SEABROOK NO 1	I	N		1,150	1990
10							
MAAC	ATLANTIC ELECTRIC	CUMBERLAND CTY NJ	I	G		82	1990
MAAC	BALTIMORE GAS & ELEC	BRANDON SHORES NO 2	I	T	Oil/Coal	640	1992
MAAC	DELMARVA PR & LT CO	HAY ROAD NO 1	I	G		102	1989
MAAC	DELMARVA PR & LT CO	HAY ROAD NO 2	I	G		102	1989
MAAC	EASTON MARYLAND	PLANT 2 UNIT 23	M	D		6	1989
MAAC	EASTON MARYLAND	PLANT 2 UNIT 24	M	D		6	1989
MAAC	JERSEY CENTRAL P & L	FORKED RIVER NO 1	I	G		35	1989
MAAC	JERSEY CENTRAL P & L	FORKED RIVER NO 2	I	G		35	1989
MAAC	PHILADELPHIA ELEC CO	LIMERICK NO 2	I	N		1,055	1990
MAAC	POTOMAC ELEC POWER CO	BENNING CT NO 1	I	G		105	1990
MAAC	POTOMAC ELEC PR CO	BENNING CT NO 2	I	G		105	1991
MAAC	POTOMAC ELEC PR CO	DICKERSON	I	G		125	1994
12							
ECAR	AMERICAN ELEC PR CO	ROCKPORT NO 2	I	T	Coal	1,300	1989
ECAR	+ CINN GAS & ELEC CO	ZIMMER	I	T	Coal	1,300	1991
ECAR	DETROIT MICHIGAN	MUNICIPAL	M	T		58	1989
ECAR	E KENTUCKY PWR COOP	SMITH NO 1	C	T	Coal	600	1901
ECAR	LOUISVILLE GAS & EL	TRIMBLE COUNTY NO 1	I	T	Coal	495	1991
5							

TABLE 17 -- SCHEDULED ADDITIONS as of JANUARY 1, 1989, continued

REGION	SYSTEM	UNIT	OWNER-SHIP	TYPE	STEAM FOSSIL FUELS	MW of NET EXPECTED CAPABILITY	SKED YEAR OPTN
SERC	ALABAMA POWER COMPANY	MILLER NO 3	I	T	Coal	667	1989
SERC	ALABAMA POWER COMPANY	MILLER NO 4	I	T	Coal	667	1991
SERC	DUKE POWER COMPANY	BAD CREEK NO 1	I	R		250	1991
SERC	DUKE POWER COMPANY	BAD CREEK NO 2	I	R		250	1991
SERC	DUKE POWER COMPANY	BAD CREEK NO 3	I	R		250	1991
SERC	DUKE POWER COMPANY	BAD CREEK NO 4	I	R		250	1991
SERC	FLORIDA PR & LT CO	PT EVERGLADES NO 5	I	T		11	1990
SERC	FORT PIERCE FLORIDA	KING	M	G		30	1989
SERC	+ GEORGIA POWER COMPANY	SCHERER NO 4	I	T	Coal	849	1989
SERC	+ GEORGIA POWER COMPANY	VOGTLE NO 2	I	N		1,086	1989
SERC	ORLANDO FLORIDA	ORLANDO A	M	G		35	1989
SERC	ORLANDO FLORIDA	ORLANDO B	M	G		35	1989
SERC	SO CAR PUB SERV AUTHY	CROSS NO 1	SL	T	Coal	500	1999
SERC	TENNESSEE VALLEY AUTHY	BELLEFONTE NO 1	F	N		1,213	1998
SERC	TENNESSEE VALLEY AUTHY	BELLEFONTE NO 2	F	N		1,213	1999
SERC	TENNESSEE VALLEY AUTHY	WATTS BAR NO 1	F	N		1,177	1992
SERC	TENNESSEE VALLEY AUTHY	WATTS BAR NO 2	F	N		1,177	1996
SERC	VIRGINIA EL & PR CO	CHESTERFIELD NO 7	I	T		58	1990
SERC	VIRGINIA EL & PR CO	CHESTERFIELD VA	I	G		127	1990
SERC	VIRGINIA EL & PR CO	GRAVEL NECK NO 1	I	G		82	1989
SERC	VIRGINIA EL & PR CO	GRAVEL NECK NO 2	I	G		82	1989
SERC	VIRGINIA EL & PR CO	GRAVEL NECK NO 3	I	G		82	1989
SERC	VIRGINIA EL & PR CO	GRAVEL NECK NO 4	I	G		82	1989
23							
SPP	SPRINGFIELD MISSOURI	SPRINGFIELD GT NO 1	M	G		71	1989
SPP	ST JOSEPH LT & PR CO	LAKE ROAD UT GT	I	G		15	1989
2							

REGION	SYSTEM	UNIT	OWNER-SHIP	TYPE	STEAM FOSSIL FUELS	MW of NET EXPECTED CAPABILITY	SKED YEAR OPTN
ERCOT	HOUSTON LTG & PR CO	MALAKOFF NO 1	I	T	Coal	645	1996
ERCOT	HOUSTON LTG & PR CO	MALAKOFF NO 2	I	T	Coal	645	1998
ERCOT	+ HOUSTON LTG & PR CO	SOUTH TEXAS NO 2	I	N		1,250	1989
ERCOT	SAN ANTONIO TEXAS	J K SPRUCE NO 1	M	T	Coal	498	1992
ERCOT	+ TEXAS UTILITY CO SYSTEM	COMANCHE PEAK NO 1	I	N		1,150	1989
ERCOT	+ TEXAS UTILITY CO SYSTEM	COMANCHE PEAK NO 2	I	N		1,150	1991
ERCOT	TEXAS UTILITY CO SYSTEM	DE CORDOVA CT NO 1	I	G		65	1990
ERCOT	TEXAS UTILITY CO SYSTEM	DE CORDOVA CT NO 2	I	G		65	1990
ERCOT	TEXAS UTILITY CO SYSTEM	DE CORDOVA CT NO 3	I	G		65	1990
ERCOT	TEXAS UTILITY CO SYSTEM	DE CORDOVA CT NO 4	I	G		65	1990
ERCOT	+ TEXAS UTILITY CO SYSTEM	FOREST GROVE NO 1	I	T	Coal	750	1997
ERCOT	TEXAS UTILITY CO SYSTEM	PERMIAN BASIN CT 4	I	G		65	1990
ERCOT	TEXAS UTILITY CO SYSTEM	PERMIAN BASIN CT 5	I	G		65	1990
ERCOT	+ TEXAS UTILITY CO SYSTEM	TWIN OAK NO 1	I	T	Coal	750	1994
ERCOT	+ TEXAS UTILITY CO SYSTEM	TWIN OAK NO 2	I	T	Coal	750	1995
15							
MAPP	IOWA PR & LT COMPANY	PLEASANT HILL A	I	G		38	1990
MAPP	IOWA PR & LT COMPANY	PLEASANT HILL B	I	G		38	1990
2							
WSCC	NEVADA POWER COMPANY	CLARK NO 9	I	TC		90	1993
WSCC	NEVADA POWER COMPANY	CLARK NO 10	I	TC		90	1994
WSCC	+ PUB SERV CO NEW MEXICO	NEW MEXICO STA NO 1	I	T	Coal	500	1999
WSCC	PUB SERV CO NEW MEXICO	NEW MEXICO STA NO 2	I	T	Coal	500	1999
WSCC	PUB SERV CO NEW MEXICO	NEW MEXICO STA NO 3	I	T	Coal	500	1999
WSCC	PUB SERV CO NEW MEXICO	NEW MEXICO STA NO 4	I	T	Coal	500	1999
WSCC	PUB SERV CO OF COLORADO	PAWNEE NO 2	I	T	Coal	485	1998
WSCC	SANTA CLARA CALIFORNIA	BLACK BUTTE DAM	M	H		6	1989
WSCC	TUCSON ELEC PR COMPANY	SPRINGERVILLE NO 2	I	T	Coal	360	1990
WSCC	VERNON CALIFORNIA	COMBUSTION TURBINE	SL	G		11	1989
WSCC	+ WASHINGTON PUB PR SPLY	WNP NO 1	SL	N		1,250	1999
WSCC	+ WASHINGTON PUB PR SPLY	WNP NO 3	SL	N		1,240	1999
12							
					81 units:	32,627 MW	

PART III. MANUFACTURE OF HEAVY ELECTRIC POWER EQUIPMENT (HISTORICAL AND SCHEDULED)

Data in this section of the report relate to the manufacture in the United States of heavy electric power equipment for U.S. electric utility systems, U.S. industrials and for export to customers outside the United States. Information is also included on actual and scheduled imports of such equipment by U.S. electric utility systems and U.S. industrials.

Orders placed with domestic and foreign manufacturers during 1988 for heavy electric power equipment by U.S. electric utility systems are shown in the accompanying order synopsis table (Table 18), together with corresponding information for the previous four years.

Detailed data, as of January 1, 1989, concerning 1988 orders, shipments, scheduled shipments, and total production backlogs of domestic manufacturers for the three customer classes are shown in the series of tables that follow, along with analogous information on imports of certain types of equipment by U.S. electric utility systems and U.S. industrial customers.

During 1988 orders for new steam and hydraulic electric generating units placed with domestic manufacturers totaled 23 machines aggregating 1,560 megawatts.

U.S. electric utility systems accounted for 55 percent of this total capacity, and U.S. industrials took the remaining 45 percent, as export orders were zero. The only orders placed in 1988 with foreign manufacturers by U.S. electric utility systems were for two water-wheel generators and the associated hydraulic turbines representing 126 MW, and two combustion turbines totaling 200 MW. In contrast to the low level of foreign ordering by utilities, U.S. industrials ordered 16 steam turbine-generators aggregating 779 megawatts, and seven combustion turbines totaling 448 megawatts. Production by domestic manufacturers during the year 1988 amounted to 2.8 thousand MW, of which only 707 MW were delivered to U.S. electric utility systems. The total production scheduled as of January 1, 1989, for all classes of customers amounts to 85 units totaling 37.7 thousand megawatts. The manufacturing schedule for 1989 totals 2.1 thousand megawatts. The 1990 and later schedule, up to now, calls for the production of 59 units totaling 35.6 thousand megawatts.

Table 18 – CAPACITIES OF VARIOUS TYPES OF HEAVY ELECTRIC POWER EQUIPMENT ORDERED BY U.S. ELECTRIC UTILITY SYSTEMS FROM DOMESTIC AND FOREIGN MANUFACTURERS

	1984	1985	1986	1987	1988
Electric Generating Units (4,000 kW and Larger)					
Steam Turbine-Generators, kW					
Conventional	683,100	1,379,454	--	220,400	860,600
Nuclear	--	--	--	--	--
Geothermal, kW	139,240 (a)	168,000 (a)	--	--	--
Solar, kW	30,000	90,000	--	--	--
Combustion Turbine-Generators, kW	162,000	24,800	751,800	824,500 (a)	1,571,300 (a)
Generators for Hydraulic Turbines, kW	--	69,200	--	20,400 (a)	126,000 (a)
	1,014,340 (a)	1,731,454 (a)	751,800	1,065,300 (a)	2,557,900 (a)
Steam Generators, 1,000 Lb Steam Per Hour	3,900	--	9,775	--	250
Nuclear Power Reactors (50,000 kWe and Larger)	--	--	--	--	--
Hydraulic Turbines, Hp	--	--	77,200 (a)	--	145,600
Power Transformers, Mva (b)	65,688	65,037	79,662	78,233	82,502

(a) Includes equipment on order with foreign manufacturers.
(b) Includes U.S. industrials.

Table 19 MANUFACTURE OF ELECTRIC GENERATING EQUIPMENT

STEAM and HYDRAULIC UNITS* -- 4,000 kW and Larger

Customer	Shipped	Scheduled as of January 1, 1989		Total Scheduled for Shipment as of 1-1-89	New Orders Booked
	1988	1989	1990 and Later		1988
U.S. Electric Utility Systems					
Units	4	4	46	50	5
kW	706,600	241,700	27,466,570	27,708,270	860,600
U.S. Industrials					
Units	29	18	1	19	18
kW	904,900	517,275	15,600	532,875	699,675
Exports from U.S.					
Units	7	4	12	16	-
kW	1,149,000	1,337,380	8,094,000	9,431,380	-
Total					
Units	40	26	59	85	23
kW	2,760,500	2,096,355	35,576,170	37,672,525	1,560,275

* Does not include Combustion Turbine-Generators, but does include Steam Turbine-Generators for Nuclear Power Plants.

** Manufacturers' Ratings.

Table 20 MANUFACTURE OF STEAM TURBINE-GENERATORS

4,000 kW and Larger

Customer	Shipped	Scheduled as of January 1, 1989		Total Scheduled for Shipment as of 1-1-89	New Orders Booked
	1988	1989	1990 and Later		1988
U.S. Electric Utility Systems					
Units	4	4	46	50	5
kW	706,600	241,700	27,466,570	27,708,270	860,600
U.S. Industrials					
Units	29	18	1	19	18
kW	904,900	517,275	15,600	532,875	699,675
Exports from U.S.					
Units	7	4	12	16	-
kW	1,149,000	1,337,380	8,094,000	9,431,380	-
Total					
Units	40	26	59	85	23
kW	2,760,500	2,096,355	35,576,170	37,672,525	1,560,275

Table 20-A MANUFACTURE OF CONVENTIONAL STEAM TURBINE-GENERATORS

4,000 kW and Larger (Included in Table 20)

Customer	Shipped	Scheduled as of January 1, 1989		Total Scheduled for Shipment as of 1-1-89	New Orders Booked
	1988	1989	1990 and Later		1988
U.S. Electric Utility Systems					
Units	4	4	46	50	5
kW	706,600	241,700	27,466,670	27,708,370	860,600
U.S. Industrials					
Units	29	18	1	19	18
kW	904,900	517,275	15,600	532,875	699,675
Exports from U.S.					
Units	7	3	8	11	-
kW	1,149,000	637,380	4,694,000	5,331,380	-
Total					
Units	40	25	55	80	23
kW	2,760,500	1,396,355	32,176,270	33,572,625	1,560,275
U.S.E.U.S. Orders to Foreign Manufacturers (Imports)					
Units	-	-	-	-	-
kW	-	-	-	-	-
U.S. Industrial Orders to Foreign Manufacturers					
Units	18	23	1	24	16
kW	905,200	1,338,900	67,000	1,405,900	778,900

Table 20-B MANUFACTURE OF NUCLEAR STEAM TURBINE-GENERATORS

50,000 kWe and Larger (Included in Table 20)

Customer	Shipped	Scheduled as of January 1, 1989		Total Scheduled for Shipment as of 1-1-89	New Orders Booked
	1988	1989	1990 and Later		1988
U.S. Electric Utility Systems					
Units	-	-	-	-	-
kW	-	-	-	-	-
U.S. Industrials					
Units	-	-	-	-	-
kW	-	-	-	-	-
Exports from U.S.					
Units	-	1	4	5	-
kW	-	700,000	3,400,000	4,100,000	-
Total					
Units	-	1	4	5	-
kW	-	700,000	3,400,000	4,100,000	-
U.S.E.U.S. Orders to Foreign Manufacturers (Imports)					
Units	-	-	-	-	-
kW	-	-	-	-	-

Table 21 MANUFACTURE OF GENERATORS FOR HYDRAULIC TURBINES* – 4,000 kW and Larger

Customer	Shipped	Scheduled as of January 1, 1989		Total Scheduled for Shipment as of 1-1-89	New Orders Booked
	1988	1989	1990 and Later		1988
U.S. Electric Utility Systems					
Units	–	–	–	–	–
kW	–	–	–	–	–
U.S. Industrials					
Units	–	–	–	–	–
kW	–	–	–	–	–
Exports from U.S.					
Units	–	–	–	–	–
kW	–	–	–	–	–
Total					
Units	–	–	–	–	–
kW	–	–	–	–	–
U.S.E.U.S. Orders to Foreign Manufacturers (Imports)					
Units	–	4	2	6	2
kW	–	689,400	563,400	1,252,800	126,000
U.S. Industrial Orders to Foreign Manufacturers					
Units	2	2	–	2	–
kW	134,400	28,400	–	28,400	–

Table 22 MANUFACTURE OF CONVENTIONAL STEAM GENERATORS -- 450 Psi and Higher

Customer	Shipped	Scheduled as of January 1, 1989		Total Scheduled for Shipment as of 1-1-89	New Orders Booked
	1988	1989	1990 and Later		1988
U.S. Electric Utility Systems					
Units	1	6	6	12	1
M Lb/Hr	4,961	29,950	32,037	61,987	250
U.S. Industrials					
Units	7	4	-	4	5
M Lb/Hr	1,230	288,000	-	288,000	134,518
Exports from U.S.					
Units	2	2	-	2	-
M Lb/Hr	8,068	8,068	-	8,068	-
Total					
Units	10	12	6	18	6
M Lb/Hr	14,259	326,018	32,037	358,055	134,768

Table 23 MANUFACTURE OF HYDRAULIC TURBINES

5,000 Horsepower and Larger

Customer	Shipped	Scheduled as of January 1, 1989		Total Scheduled for Shipment as of 1-1-89	New Orders Booked
	1988	1989	1990 and Later		1988
U.S. Electric Utility Systems					
Units	-	-	7	7	2
Hp	-	-	1,499,360	1,499,360	19,360
U.S. Industrials					
Units	5	2	3	5	1
Hp	30,005	14,000	89,885	103,885	4,000
Exports from U.S.					
Units	-	-	1	1	-
Hp	-	-	135,000	135,000	-
Total					
Units	5	2	11	13	23
Hp	30,005	14,000	1,724,245	1,738,245	1,560,275
U.S.E.U.S. Orders to Foreign Manufacturers (Imports)					
Units	3	2	-	2	2
Hp	18,600	126,240	-	126,240	126,240
U.S. Industrial Orders to Foreign Manufacturers					
Units	1	-	-	-	-
Hp	31,300	-	-	-	-

Table 24 MANUFACTURE OF COMBUSTION TURBINE-GENERATORS

4,000 kW and Larger

Customer	Shipped	Scheduled as of January 1, 1989		Total Scheduled for Shipment as of 1-1-89	New Orders Booked
	1988	1989	1990 and Later		1988
U.S. Electric Utility Systems					
Units	14	3	8	11	20
kW	1,053,500	96,600	626,200	722,800	1,371,300
U.S. Industrials					
Units	17	10	15	25	26
kW	962,400	359,000	703,900	1,062,900	1,198,300
Exports from U.S.					
Units	8	9	1	10	12
kW	687,400	769,200	38,300	807,500	835,500
Total					
Units	39	22	24	46	23
kW	2,703,300	1,224,800	1,368,400	2,593,200	1,560,275
U.S.E.U.S. Orders to Foreign Manufacturers (Imports)					
Units	-	4	-	4	2
kW	-	400,000	-	400,000	200,000
U.S. Industrial Orders to Foreign Manufacturers					
Units	1	10	1	11	7
kW	13,800	1,645,500	93,800	1,739,300	447,500

Table 25 MANUFACTURE OF NUCLEAR REACTORS

50,000 kWe and Larger

Customer	Completed	Scheduled as of January 1, 1989		Total Scheduled as of 1-1-89	New Orders Booked
	1988	1989	1990 and Later		1988
U.S. Electric Utility Systems					
Units	6	4	10	14	-
kWe	6,970,000	4,333,000	11,957,000	16,290,000	-
Exports from U.S.					
Units	1	1	7	8	-
kWe	920,000	654,000	7,086,000	7,740,000	-
Total					
Units	7	5	17	22	-
kWe	7,890,000	4,987,000	19,043,000	24,030,000	-

Table 26 -- MANUFACTURE OF POWER TRANSFORMERS, 501 kVA and Larger

Customer		Shipped 1988	Scheduled as of January 1, 1989: 1989	1990	1991	1992	1993	1994	1995 and Later	Total Scheduled for Shipment as of 1-1-89	Orders Booked 1988
					501 to 10,000 kVA						
U.S. Electric Power Systems and U.S. Industrials	(Units	4,446	2,271	202	-	9	-	-	-	2,482	5,035
	(MVA	10,968	5,905	510	-	41	-	-	-	6,456	12,787
Exports from U.S.	(Units	121	53	-	-	2	-	-	-	55	155
	(MVA	566	145	-	-	12	-	-	-	157	438
TOTAL	(Units	4,567	2,324	202	-	11	-	-	-	2,537	5,190
	(MVA	11,534	6,050	510	-	53	-	-	-	6,613	13,225
					10,001 to 30,000 kVA						
U.S. Electric Power Systems and U.S. Industrials	(Units	675	520	17	-	7	-	-	-	544	722
	(MVA	17,573	10,760	435	-	123	-	-	-	11,318	15,922
Exports from U.S.	(Units	17	16	-	-	-	-	-	-	16	10
	(MVA	447	377	-	-	-	-	-	-	377	181
TOTAL	(Units	692	536	17	-	7	-	-	-	560	732
	(MVA	18,020	11,137	435	-	123	-	-	-	11,695	16,104
					30,001 to 100,000 kVA						
U.S. Electric Power Systems and U.S. Industrials	(Units	291	278	28	-	-	-	-	-	306	354
	(MVA	19,300	17,290	1,347	-	-	-	-	-	18,637	22,817
Exports from U.S.	(Units	-	-	-	-	-	-	-	-	-	-
	(MVA	-	-	-	-	-	-	-	-	-	-
TOTAL	(Units	291	278	28	-	-	-	-	-	306	354
	(MVA	19,300	17,290	1,347	-	-	-	-	-	18,637	22,817
					100,000 kVA and Larger						
U.S. Electric Power Systems and U.S. Industrials	(Units	96	86	10	-	1	-	-	-	97	99
	(MVA	28,036	26,368	2,633	-	815	-	-	-	29,816	30,976
Exports from U.S.	(Units	-	2	-	-	-	-	-	-	2	2
	(MVA	-	750	-	-	-	-	-	-	750	750
TOTAL	(Units	96	88	10	-	1	-	-	-	99	101
	(MVA	28,036	27,118	2,633	-	815	-	-	-	30,566	31,726
					Total (501 kVA and Larger)						
U.S. Electric Power Systems and U.S. Industrials	(Units	5,508	3,155	257	-	17	-	-	-	3,429	6,210
	(MVA	75,878	60,323	4,925	-	979	-	-	-	66,227	82,502
Exports from U.S.	(Units	138	71	-	-	2	-	-	-	73	167
	(MVA	1,013	1,272	-	-	12	-	-	-	1,284	1,369
TOTAL	(Units	5,646	3,226	257	-	19	-	-	-	3,502	6,377
	(MVA	76,891	61,595	4,925	-	991	-	-	-	67,511	83,872